TESTIMONY OF
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HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Project Cost

INTRODUCTION

Q. Please state your name and business address.

A. My name is Earlynne F. Oshiro and my business address is 820 Ward Avenue, Honolulu, Hawaii.

Q. What is your present position with the Hawaiian Electric Company, Inc. ("HECO")?

A. I am an Engineer in the Substation, Protection & Telecommunications Division in the Engineering Department. My educational background and experience are provided in HECO-900.

Q. What is the scope of your testimony?

A. My testimony will address the development of the cost estimates, revenue requirements and the forecasted impact on customer rates for the three transmission system alternatives presented to the public for input in 2003 for the East Oahu Transmission Project.

PROJECT COST

Introduction

Q. What were the three transmission system alternatives presented to the public for input in 2003 for the East Oahu Transmission Project?

A. The three alternatives were: 1) Kamoku-Pukele 138 kV Underground Alternative (via Palolo); 2) Kamoku 46 kV Underground Alternative; and 3) Kamoku 46 kV Underground Alternative – Expanded.

Q. Please briefly describe the three alternatives that were presented and evaluated.

A. For cost estimating purposes, the alternatives can be grouped into two categories: (1) an underground 138 kV transmission alternative, and (2) underground 46 kV subtransmission alternatives.

In category (1), the Kamoku-Pukele 138 kV Underground Alternative via Palolo involves the installation of an underground 138 kV transmission line between Kamoku Substation and Pukele Substation utilizing existing roadways. Either extruded dielectric, cross-linked polyethylene ("XLPE") cables or high-pressure fluid filled ("HPFF") cables could be used for the 138 kV underground transmission line. Mr. Wong's testimony, HECO T-6, explains the differences between the cable types. 138 kV termination equipment would be needed at Kamoku and Pukele Substations for this alternative.

In category (2), the Kamoku 46 kV Underground Alternative involves the installation of several underground XLPE 46 kV lines in existing roadways in and around the Ala Moana, McCully, Moiliili, and Kapahulu areas. In addition to the new 46 kV underground lines, a new 138 kV to 46 kV transformer would be installed at Kamoku Substation and equipment modifications would be required at various distribution substations. The distribution substations are Ena, Waikiki, Kuhio, Kapahulu, Makaloa, McCully and Kewalo.

Also in category (2), the Kamoku 46 kV Underground Alternative – Expanded can be separated into two phases. Phase 1 is essentially the Kamoku 46 kV Underground Alternative described above. Phase 2 involves the installation of three XLPE 46 kV lines in a single duct line from Archer Substation on Cooke Street to McCully Street utilizing King Street. Phase 2 also requires the installation of a new 138 kV to 46 kV transformer at Archer Substation.

These alternatives are discussed in the HECO Technical Memo titled "East Oahu Transmission Line Project Cost Estimate Development for the Evaluated Alternatives," (pages 1 to 3), which is attached as HECO-901.

Q. What sources of information were used to develop the cost estimates for the alternatives being considered?

A. HECO used various sources including estimates and actual costs from previous HECO projects, and estimates from industry consultants and material suppliers.

Q. Over what time period were the costs associated with each alternative evaluated?

A. Yearly costs associated with each of the alternatives were evaluated over a period of 50 years. It should be noted that this 50-year period is not the definitive life of the projects, but rather a period in which the alternatives can be compared over a definitive duration. Transmission, subtransmission and substation systems have different life expectancies due to the difference in technology and physical characteristics. Therefore, in our analysis, we have identified specific cost factors that may be applicable to only certain alternatives during certain years and have made every attempt to maintain consistency in our assumptions.

Q. What costs are included in the cost estimate for each alternative?

A. The cost estimate for each alternative includes the following costs: (1) initial installation, (2) removal, (3) new cycle, (4) operation & maintenance, and (5) transmission system losses.

<u>Initial Installation Costs</u>

Q. What costs are included in the initial installation cost estimates?

A. Initial installation cost estimates include (a) planning costs, (b) permit and approval costs, including environmental assessment or environmental impact statement costs, (c) materials costs, (d) labor costs, (e) land costs, and (f) allowance for funds used during construction ("AFUDC"). Detailed engineering studies will be conducted to confirm the initial installation cost estimates following final selection of a preferred alternative. However, the preliminary estimates used to calculate the initial installation costs are sufficient to support selection analyses and comparisons between the alternatives.

Q. What are included in the planning costs?

A. As discussed in Mr. Wong's testimony, HECO T-2, this project began in 1991 when HECO first identified the need to address the East Oahu transmission problems and concerns. HECO has been making every effort to resolve these problems and concerns. The alternative proposed in this Application addresses the problems and concerns identified in 1991. HECO has expended substantial time and resources for transmission planning studies that established the need for the project, studies that identified and evaluated various alternatives, the public scoping process and public input processes, and the environmental impact statement and Conservation District Use Permit application process for the initial preferred alternative (Kamoku-Pukele 138 kV Transmission Line utilizing Waahila Ridge). The planning costs category include the costs that were incurred prior to (and that led to) the selection of the proposed project for which approval is requested in this Application.

Q. What are included in the permitting and approval costs?

A. The permitting and approval costs include activities associated with securing the necessary permits and approvals associated with a particular alternative. The permitting and approval assumptions for the three alternatives presented to the public in June/July 2003 are discussed in Mr. Wong's testimony, HECO T-6.

Q. What schedules were assumed in developing the initial installation costs?

A. As discussed in Mr. Wong's testimony, HECO T-6, the following in-service dates were assumed: (1) Kamoku-Pukele 138 kV Underground Alternative, 2010; (2) Kamoku 46 kV Underground Alternative, 2006; and (3) Kamoku 46 kV

Underground Alternative – Expanded, 2008.

Q. What is the initial installation cost associated with the Kamoku-Pukele 138 kV Underground Alternative using HPFF type cable?

A. The total initial installation cost for this alternative is estimated at approximately $122.1 million. (See HECO-901, page 10.)

Q. What major permits or approvals were assumed that contributed to this cost estimate?

A. As discussed in Mr. Wong's testimony, HECO T-6, the following major permits or approvals were assumed:

- City Development Plan Public Facilities Map Amendment (PFMA) or City Revision of the Public Infrastructure Map (PIM).
- Public Utilities Commission (PUC) Review and Approval.
- Easement Acquisition from the City's Department of Budget & Fiscal Services, Purchasing Division.
- Chapter 343 Environmental Impact Statement

Q. What major materials are included in this estimate?

A. The major materials included in this estimate consist of the following: 8" steel pipe, 5" steel fluid return pipe, 138 kV HPFF cable, manholes, joints, terminators and the costs associated with the 138 kV pressurizing plant that will be required for this alternative. Major equipment required within the transmission substations includes 138 kV GIS circuit breakers and relay and control equipment. (See HECO-901 page 2, Tables 1 and 3.)

Q. What is the initial installation cost associated with the Kamoku-Pukele 138 kV Underground Alternative using XLPE type cable?

A. The total initial installation cost for this alternative is estimated at approximately

$109.5 million. (See HECO-901, page 10.)

Q. What major permits or approvals were assumed that contributed to this cost estimate?

A. As discussed in Mr. Wong's testimony, HECO T-6, the following major permits or approvals were assumed:

- City Development Plan Public Facilities Map Amendment (PFMA) or City Revision of the Public Infrastructure Map (PIM).
- Public Utilities Commission (PUC) Review and Approval.
- Chapter 343 Environmental Impact Statement

Q. What major materials are included in this estimate?

A. The major materials included in this estimate consist of the following: 138 kV duct bank, 138 kV XLPE cable, manholes, splice and terminators. Similar to the HPFF alternative, major equipment required within the transmission substations includes 138 kV GIS circuit breakers and relay and control equipment. (See HECO-901, page 2, Tables 2 and 3.)

Q. What is the initial installation cost associated with the Kamoku 46 kV Alternative?

A. The total initial installation cost for this alternative is estimated at approximately $40.6 million. (See HECO-901, page 10.)

Q. What major permits or approvals were assumed that contributed to this cost estimate?

A. As discussed in Mr. Wong's testimony, HECO T-6, the following major permits and approvals were assumed:

- City Conditional Use Permit (CUP) – minor.
- Public Utilities Commission (PUC) Review and Approval.

Q. What is the initial installation cost associated with the Kamoku 46 kV Alternative - Expanded?

A. The total initial installation cost for this alternative is estimated at approximately $58.7 million. (See HECO-901, page 10.)

Q. What major permits or approvals were assumed that contributed to this cost estimate?

A. As discussed in Mr. Wong's testimony, HECO T-6, the following major permits and approvals were assumed:

- City Conditional Use Permit (CUP) – minor.
- Public Utilities Commission (PUC) Review and Approval.

Q. What major materials are included in the 46 kV estimates?

A. The major materials included in the estimates consist of the following: 46 kV duct bank, 46 kV XLPE cable, manholes, splices, terminators and riser poles. Major equipment required within the transmission substations includes 138-46 kV 80 MVA transformers, 138 kV GIS circuit breakers and relay and control equipment. Major equipment required within the distribution substations consists of the following: 46 kV disconnect switches, 46 kV switch interrupters, motor operators, 48 VDC battery banks and battery cabinets. See HECO-901, pages 2 through 4 (Tables 4 and 5).

<u>Removal Costs and New Cycle Costs</u>

Q. Please describe how removal costs were calculated.

A. For each alternative, removal costs were calculated on the basis of the major material that would have to be removed at the end of their expected life. Removal costs for the underground segments were calculated on a per foot basis and include removal of the cable for the XLPE system. Removal costs for the substation equipment include the removal of the equipment. Based on HECO's experience and engineering practice, all ducts, steel pipes, manholes, foundations and structural improvements are expected to remain in usable condition beyond the 50-year evaluation period.

Q. Have you determined the removal costs associated with removing major equipment with a useful life less than the 50-year evaluation period?

A. Yes. HPFF and XLPE cable systems perform similar functions, but differ in the respective life assumed for each. For 138 kV HPFF cable systems, a life expectancy of 50 years is anticipated. For 138 kV XLPE cable systems, a minimum life expectancy of 35 years can be expected. These periods were selected based upon the results of utility surveys, which HECO prepared and conducted with domestic utilities. Based on past HECO experience, the 46 kV XLPE distribution cable has a life expectancy of 37 years.

Major substation equipment with a useful life ranging from 30 to 50 years include 138 kV GIS breakers, 138-46 kV 80 MVA transformers, protective relay panels, and 138 kV circuit switchers. These estimates are based on HECO historical experience. Miscellaneous transmission and distribution substation equipment has a useful life ranging from 4 to 30 years. Miscellaneous transmission substation equipment includes lightning arresters, insulators, potential transformers, circuit breaker panels, RTUs, RTU junction boxes, yard interface cabinets, and 46 kV terminations. Miscellaneous distribution substation equipment include 46 kV disconnect switches, interrupters, motor operators, battery banks, and battery cabinets. Past experience indicates that not all materials will reach the end of life expectancy during the same year. Some may reach the end of their useful life prematurely while others may very well exceed this expectation. It is difficult to estimate the useful life for such a diverse group. The useful life for small, miscellaneous transmission and distribution substation equipment is assumed to be an average of 15 years.

The major material useful life used in the cost estimates are provided in HECO-901, page 5, Table 6.

Q. Have the costs associated with new materials installed to replace initially installed materials that have reached the end of their life expectancy been included in the cost estimates?

A. Yes. These costs are referred to as "New Cycle" costs. It is assumed for consistency that all materials with an expected finite life will be replaced at the end of the predetermined life expectancy regardless of condition. New cycle costs are expected to occur during the same year that removal costs occur. For this analysis, it is assumed that new cycle materials are new materials with an estimated full life expectancy.

<u>Operation and Maintenance Costs</u>

Q. Have the costs associated with the operation and maintenance of these alternatives been included in the evaluation?

A. Yes. Operation and maintenance ("O&M") costs will be required to maintain the integrity of the system and ensure proper performance. In an effort to maintain consistency, O&M costs were determined using historical HECO costs as reported in the FERC Form No. 1: Annual Report of Major Electric Utilities, for the Year Ending December 31, 2002 ("2002 FERC Form No. 1"). In the case of the 138 kV transmission alternatives, O&M costs were calculated on a per mile basis. The total transmission O&M costs as reported in the 2002 FERC Form No. 1 was divided by the total number of miles of transmission lines to determine the cost per mile. The result is an annual cost of $18,700/mile. (See HECO-901, page 6, Table 7.)

In the case of the 46 kV subtransmission alternatives, O&M costs were calculated on a per mile basis. The total distribution O&M costs as reported in the 2002 FERC Form No. 1 was divided by the total number of miles of distribution lines to determine the cost per mile. The result is an annual cost of $6,600/mile. (See HECO-901, page 6, Table 7.)

For the transformer installations at transmission substations (Kamoku and Archer) associated with the 46 kV alternatives, O&M costs were calculated on a per MVA basis. The total transmission substation O&M costs as reported in the 2002 FERC Form No. 1 was divided by the total number of installed transmission transformer MVA to determine the cost per MVA. The result is $630/MVA. (See HECO-901, page 6, Table 7.)

Q. Are there other annual costs associated with O&M that are not included in the above?

A. Yes. The 138 kV GIS equipment is considered maintenance free. However, an annual cost of $3,400 per transmission substation site was included for an annual inspection. The additional maintenance costs associated with the equipment installed at the various distribution substations is negligible. However, an annual cost of $2,100 per distribution substation site was included for inspection and adjustments.

<u>Transmission System Losses</u>

Q. Were the costs of transmission system losses calculated for each alternative?

A. Yes. Transmission system losses were calculated for each alternative and compared to the Kamoku-Pukele 138 kV Underground Alternative with HPFF cables. For the analysis, the system peak loss and MWh or energy losses were calculated. The system peak loss is the MW loss, at the system peak under normal operation of all transmission lines and generator step-up transformers. The MWh losses are the total annual (365 days) MWh energy loss. The MWh losses are calculated by adding the MW losses at every hour over 365 days. In calculating the annual losses, the August 2002, HECO 20-year Sales and Peak Load Forecast and the 2002 HECO load duration curves were used.

In addition, because our analysis covers a period of 50 years and HECO's system forecast extends only to 2022, the losses for the year 2022 are repeated for the remaining years thereafter throughout the 50-year period. HECO-901, page 12, shows calculated transmission line losses in dollars for the alternatives relative to the Kamoku-Pukele 138 kV Underground Alternative with HPFF cables.

<u>Line Relocation Costs</u>

Q. Did you consult with government agencies to determine if there were any possible areas of conflict with future projects that may require relocating in the future the HECO duct lines installed for any of the alternatives to this project?

A. Yes. HECO consulted with various City agencies including the following: Honolulu Board of Water Supply, Design and Construction Department, Environmental Services Department, Facility Maintenance Department and Transportation Services Department.

Q. Did you identify any conflicts that may require HECO to relocate in the future duct lines installed for any of the alternatives to this project?

A. Yes, HECO has identified planned City projects that pose a potential conflict with HECO's proposed alternatives. However, our analysis indicates that these planned City projects should not require HECO to relocate installed duct lines in the future. As a result, no costs associated with relocating underground lines after installation are included in the cost estimates.

Q. Please identify these planned City projects.

A. The City Environmental Services Department has a planned Palolo Relief Sewer project scheduled for completion in 2011. This project runs in Palolo Avenue and poses a potential conflict with the Kamoku-Pukele 138 kV Underground Alternative. Since this project is scheduled for completion in 2011, HECO would be able to coordinate detailed design with the City in an effort to avoid conflicts.

The City Environmental Services Department also has a planned Cooke Street Relief Sewer project scheduled for completion in 2015. This project runs in Cooke and King Streets and poses a potential conflict with Phase 2 of the Kamoku 46 kV Underground Alternative – Expanded. This sewer line, which ranges in diameter from 10" to 24", will run parallel to the existing sewer line on King Street. At this time, engineers from the Environmental Services Department do not believe that the proposed sewer line would take up so much space that it will require HECO to relocate the installed underground line.

The City Transportation Services Department is planning to use King Street for the proposed Bus Rapid Transit project. The pavement of the mauka and makai lanes of King Street will be replaced with concrete for the City's project. If the proposed underground line on King Street between Cooke and Pensacola Streets needs to be installed in those lanes, the concrete will make duct line construction or repair more difficult and expensive. However, it appears that sufficient space on King Street is available to avoid installing the proposed underground line in the mauka or makai lanes.

Q. What are the results of HECO's analysis?

A. HECO's analysis has determined that these planned projects will not require future relocations of facilities after initial installation. Therefore, no costs associated with relocating the underground line after initial installation are included.

Other Costs

Q. Have costs associated with vegetation management been included in this evaluation?

A. No. The lines with all alternatives are proposed for underground construction in existing paved roadways, which requires no vegetation management to operate or maintain the lines. Therefore, no costs associated with vegetation management are included.

Q. Have costs associated with visual mitigation been included in this evaluation?

A. No. The lines with all alternatives are proposed for underground construction in existing paved roadways, which makes visual impact a non-factor. There is potential visual impact associated with the 138 kV pressurizing plant required for the Kamoku-Pukele 138 kV Underground Alternative with HPFF cables. However, the facility would be designed in accordance with local building code and designed to match the surrounding area. These factors have been included in the initial installation cost of the facility.

ANNUAL REVENUE REQUIREMENTS

Q. Based on the cost estimates and assumptions, were annual revenue requirements calculated for each alternative for the 50-year study period?

A. Yes. The revenue requirements are estimates of all the costs associated with an investment. For each alternative, the revenue requirements included the following types of costs: capital costs, removal and new cycle costs, O&M costs, and transmission line losses costs. The calculated revenue requirements for each alternative is shown in HECO-901, page 13.

Q. How were the capital costs calculated?

A. The capital costs were escalated for inflation based on the year the addition is expected to be placed into service. Capital costs include AFUDC. A revenue requirement factor is applied to the capital costs. The revenue requirements factor includes the following: depreciation, interest expense, preferred stock dividends, return on common equity, income taxes, and revenue taxes.

Q. How were O&M costs calculated?

A. O&M expenses were calculated to account for inflation and include revenue taxes on the expense (calculated by applying a revenue requirement factor).

Q. How were the costs associated with transmission line losses calculated?

A. The capacity cost related to the transmission line losses was calculated by applying a capital and fixed O&M rate ($/MW) to the incremental system peak loss (MW). The energy cost related to the transmission losses is calculated by applying a fuel and variable O&M rate ($/MWh) to the annual incremental MWh energy loss.

Q. Please describe how the annual revenue requirements for each alternative are presented in HECO-901, page 13.

A. As shown in HECO-901, page 13, the annual revenue requirements for each alternative are presented and totaled for the 50-year study period. The present value of the total annual revenue requirements for each alternative is also provided at various discount rates.

Q. What discount rates were used?

A. The following discount rates were used:

0% discount rate. Discounting a stream of payments with a 0% discount rate is equivalent to no discounting. Therefore, the total annual revenue requirements discounted at 0% is equal to the total non-discounted annual revenue requirements (i.e., present value and future value are the same).

3% discount rate. The 3% discount rate approximates the inflation rate for O&M and capital expenditures assumed throughout this comparison.

8.4% discount rate. The 8.4% discount rate represents HECO's weighted average after-tax cost of capital assumed in this comparison.

12% discount rate. The 12% discount rate was used to show the results of discounting the stream of payments with a discount rate greater than 8.4%.

The revenue requirements for each of the discount rates should be evaluated along with other factors such as the annual revenue requirements and amount of up-front investment.

Q. What is the net present value of the annual revenue requirements for the Kamoku-Pukele 138 kV alternative using HPFF cable, in 2003 dollars and using an 8.4% discount rate?

A. The net present value in 2003 dollars is $95.2 million. (See HECO-901, page 13.)

Q. What is the net present value of the annual revenue requirements for the Kamoku-Pukele 138 kV alternative using XLPE cable, in 2003 dollars and using an 8.4% discount rate?

A. The net present value in 2003 dollars is $87.1 million. (See HECO-901, page 13.)

Q. What is the net present value of the annual revenue requirements for the Kamoku 46 kV alternative, in 2003 dollars and an 8.4% discount rate?

A. The net present value in 2003 dollars is $44.9 million. (See HECO-901, page 13.)

Q. What is the net present value of the annual revenue requirements for the Kamoku 46 kV alternative - Expanded, in 2003 dollars and using an 8.4% discount rate?

A. The net present value in 2003 dollars is $56.1 million. (See HECO-901, page 13.)

Q. What percentage of the total revenue requirements is associated with the initial and future capital installation costs for the alternatives?

A. 91% to 98% of the total revenue requirements are associated with the initial and future capital installation costs.

Q. Was the ranking of the alternatives (in terms of net present value of the total revenue requirements) affected by the use of different discount rates?

A. The ranking of the alternatives remained fairly consistent even at different discount rates.

Q. Please describe the ranking of the alternatives at the different discount rates.

A. When comparing all alternatives (excluding the Kamoku 46 kV Underground Alternative – Expanded with phased installation, which is the proposed project), the net present value calculation of the total revenue requirements for the Kamoku-Pukele 138 kV Underground Alternative (HPFF) was the highest (rank #1) (i.e., it had the highest net present value of all of the alternatives); the Kamoku-Pukele 138 kV Underground Alternative (XLPE) was the second highest (rank #2); the Kamoku 46 kV UG Alternative – Expanded was the third highest (rank #3); and the Kamoku 46 kV UG Alternative was the lowest (rank #4), using the range of discount rates that were considered.

RATE IMPACT

Q. When would the cost for this project be included in the electric rates charged to customers?

A. Any rate increase to recover the cost of this project would need to be included in a separate rate increase request to the Commission by HECO, and would be filed at a later date.

Q. How was the potential rate impact on each of HECO's rate classes calculated for each of the alternatives?

A. The revenue requirements were allocated to the different rate classes (Schedule R, G, J, H, P, F) based on the demand cost allocation factors used in HECO's last rate case (Docket No. 7766) – and which were used to develop the current effective rates. (See HECO-901, page 8, for a brief description of these rate schedules.)

These demand cost allocation factors were derived from the cost of service study used and approved in Docket No. 7766. The cost of service study provides the mechanism to classify, categorize and allocate the costs of serving the different rate classes, since the costs are not recorded or reported by cost type such as customer-related cost, energy-related cost, or demand-related cost, nor are they reported by rate class schedules. HECO's cost of service study methodology is based on the National Association of Regulatory Utility Commissioners Cost Allocation methodology, which classifies transmission costs as demand-related costs.

The allocated revenue requirements were then converted into cents per kWh by dividing them by the sales forecast for the respective years for the different rate classes. The results represent the estimated rate impacts for the different classes. Rate impacts were derived for the year the alternative is placed in service until 2013. The estimated rate impacts on typical customers in the various rate schedules are shown in HECO-901, pages 14 to 20. For purposes of determining the rate impact on the typical residential customer of the various alternatives, a typical residential customer is assumed to use 667 kwh/month.

Q. In the year after the alternative is installed (2010), what is the incremental rate impact per month on the typical residential customer for the costs associated with the Kamoku-Pukele 138 kV Underground Alternative using HPFF type cable?

A. The potential impact on a typical residential customer's monthly bill would be an increase of $1.97 in 2011. (See HECO-901, page 14.)

Q. In the year after the alternative is installed (2010), what is the incremental rate impact per month on the typical residential customer for the costs associated with the Kamoku-Pukele 138 kV Underground Alternative using XLPE type cable?

A. The potential impact on a typical residential customer's monthly bill would be an increase of $1.86 in 2011. (See HECO-901, page 15.)

Q. In the year after the alternative is installed (2006), what is the incremental rate impact per month on the typical residential customer for the costs associated with the Kamoku 46 kV Underground Alternative?

A. The potential impact on a typical residential customer's monthly bill would be an increase of $0.70 in 2007. (See HECO-901, pages 16 to 17.)

Q. In the year after the alternative is installed (2008), what is the incremental rate impact per month on the typical residential customer for the costs associated with the Kamoku 46 kV Underground Alternative - Expanded?

A. The potential impact on a typical residential customer's monthly bill would be an increase of $1.00 in 2009. (See HECO-901, page 18.)

46kV PHASED PROJECT (PROPOSED PROJECT)

Q. What alternative was selected as the proposed project in this Application?

A. As discussed in Mr. Joaquin's testimony, HECO T-1, the alternative that was selected as the proposed project in this Application is the Kamoku 46 kV Underground Alternative – Expanded with "phased" installation and an environmental assessment as part of the PUC approval process. "Phased" installation means that the installation of Phase 1 and Phase 2 would be staggered as opposed to being installed simultaneously in 2008 as described above. As discussed in Mr. Wong's testimony, HECO T-6, it is estimated that Phase 1 would be installed in 2006 and Phase 2 in 2008. The proposed project is referred to as the "46 kV Phased Project".

Q. What is the initial installation cost associated with the 46 kV Phased Project?

A. The total initial installation cost for the 46 kV Phased Project is estimated at approximately $55.4 million. (See HECO-901, page 11.)

Q. How were the planning, permitting, and approval costs shown on HECO-901, page 11, allocated to the different sub-projects as shown in Exhibit 2 of the Application?

A. The planning costs as well as the permitting and approval costs are shared among various sub-projects of the 46kV Phased Project. Therefore, to determine the appropriate cost of each sub-project, these shared costs were equitably allocated.

Q. How were the planning costs allocated to the sub-projects of the 46kV Phased Project?

A. The planning costs were allocated to each sub-project based on the percentage of the overall cost that the sub-project represented. For Phase 1, the planning costs were allocated 35% to the 46 kV underground lines, 57% to Kamoku Substation and 8% to the distribution substation modifications.

Planning costs were not allocated to Phase 2. As discussed in Ms.

Ishikawa's testimony, HECO T-4, Phase 1 fully addressed the Koolau/Pukele Overload Situation and partially addressed the Pukele Substation Reliability Concern. Phase 2 addressed the remaining areas of the Pukele Substation Reliability Concern. Because Phase 1 addresses most of the East Oahu transmission problems, and can be independently completed and placed in service, the planning costs were allocated to Phase 1 and not to Phase 2. As a result, carrying costs associated with these costs will not continue to accrue after Phase 1 is completed and placed in service.

Q. How were the permitting and approval costs allocated to the sub-projects of the 46 kV Phased Project?

A. The permitting and approval costs for each respective Phase were allocated to each sub-project based on the percentage of the overall cost that the sub-project represented to its respective Phase. For Phase 1, the permitting and approval costs were allocated 35% to the 46 kV underground lines, 57% to Kamoku Substation and 8% to the distribution substation modifications. For Phase 2, 73% of the permitting and approval costs were allocated to the 46 kV underground lines and 27% to Archer Substation. Permitting and approval costs related to Phases 1 and 2, such as the cost for obtaining Commission approval of the proposed alternative and the voluntary Environment Assessment HECO will be conducting, were estimated for Phase 1 and 2.

Q. Besides costs associated with Phase 1 being constructed in 2006 as opposed to 2008, were there other costs that differentiated the 46 kV Phased Project from the Kamoku 46 kV Underground Alternative - Expanded?

A. Yes. The 46kV Phased Project has construction contingencies added for Kalakaua Avenue and King Street. As discussed in Mr. Harrington's testimony, HECO T-8, construction work on Kalakaua Avenue and King Street may require special work hour considerations to minimize traffic impacts. In addition, as discussed in Mr. Wong's testimony, HECO T-6, there could be possible scheduling conflicts with the installation of the proposed 46kV lines on King Street due to planned City-initiated projects for that same area. These potential scheduling conflicts could alter when Phase 2 construction is actually started and completed.

Another cost that differentiated the 46kV Phased Project from the Kamoku 46kV Underground Alternative – Expanded was the addition of a voluntary environmental assessment to the project scope. This is discussed further in Mr. Wong's testimony, HECO T-6.

Q. How does the initial installation cost for the 46 kV Phased Project compare to the other alternatives?

A. The initial installation cost of the 46 kV Phased Project is approximately $14.7 million more than the Kamoku 46 kV Underground Alternative but approximately $3.2 million less than the Kamoku 46 kV Underground Alternative – Expanded (Phases 1 and 2 installed simultaneously in 2008). The primary reason why the 46 kV Phased Project is less than the Kamoku 46 kV Underground Alternative – Expanded is attributed to Phase 1 being completed in 2006 versus 2008. With Phase 1 completing earlier, AFUDC costs are less and construction costs are slightly lower due to less inflation effects.

Q. What is the net present value of the annual revenue requirements for the 46 kV Phased Project in 2003 dollars and using an 8.4% discount rate?

A. The net present value in 2003 dollars is $59.9 million. (See HECO-901, page 13.)

Q. How does the net present value of the 46 kV Phased Project compare with the other alternatives?

A. With the various discount rates, the 46 kV Phased Project was higher in cost than the Kamoku 46 kV Underground Alternative and lower in cost that the Kamoku-Pukele 138 kV Underground Alternative. However, the ranking of the 46 kV Phased Project varies slightly with different discount rates when compared to the Kamoku 46 kV Underground Alternative – Expanded.

Q. What were the comparisons between the 46 kV Phased Project and the Kamoku 46 kV Underground Alternative – Expanded with different discount rates?

A. At the 0% and 3% discount rates, the 46 kV Phased Project ranked lower in cost than the Kamoku 46 kV Underground Alternative – Expanded. At the 8.4% and 12% discount rates, the 46 kV Phased Project ranked higher in cost than the Kamoku 46 kV Underground Alternative – Expanded. The reason for this is that when comparing the two alternatives, the 46 kV Phased Project results in revenue requirements beginning two years earlier (from 2006) than the Kamoku 46 kV Underground Alternative – Expanded, and the Kamoku 46 kV Underground Alternative – Expanded results in higher revenue requirements in the later years. The higher revenue requirements in the later years are given less weight in the present value calculation using the higher discount rates, which causes the present value calculation of the total revenue requirements to be slightly lower overall.

Q. In the years after the 46 kV Phased Project is installed (Phase 1 – 2006, Phase 2 - 2008), what is the incremental rate impact per month on the typical residential customer for the costs associated with this project?

A. The potential rate impact on a typical residential customer's monthly bill would be an increase of $0.72 in 2007 after Phase 1 is installed. After Phase 2 is installed, the rate impact on a typical residential customer's bill would be an increase of $0.90 in 2009. (See HECO-901, pages 19 to 20.)

Q. How does the incremental rate impact of the 46 kV Phased Project compare with the other alternatives?

A. The potential rate impact of the 46 kV Phased Project is slightly higher for the first month in 2007 ($0.72) as compared to the Kamoku 46 kV Underground Alternative ($0.70). However, the potential rate impact of the 46 kV Phased Project is slightly lower for the first month in 2009 ($0.90) as compared to the Kamoku 46 kV Underground Alternative – Expanded ($1.00).

Q. What is the estimated cost in this Application for the 46 kV Phased Project?

A. The estimated initial installation or capital cost of $55.4 million is included in this Application.

SUMMARY

Q. Please summarize your testimony.

A. Cost estimates, revenue requirements and rate impacts were calculated for all the alternatives while making every attempt to maintain consistency in our assumptions. The initial installation cost for the alternatives range from approximately $40.6 million to $122.1 million with the Kamoku-Pukele 138 kV alternative using HPFF cable having the highest capital cost and the Kamoku 46 kV alternative having the lowest capital cost. The 46 kV Phased Project proposed in this Application, which is a variation of the Kamoku 46 kV Underground Alternative – Expanded, has an estimated initial installation cost of approximately $55.4 million.

In terms of revenue requirements, the net present value (in 2003 dollars and assuming an 8.4% discount rate) of the revenue requirements for the alternatives range from $44.9 million to $95.2 million with the Kamoku-Pukele 138 kV alternative using HPFF cable having the highest and the Kamoku 46 kV alternative having the lowest net present value. The 46 kV Phased Project has a net present value of $59.9 million.

The potential incremental rate impact for the first month following the year of installation associated with the alternatives for the typical residential customer range from $0.70 to $1.97 with the Kamoku-Pukele 138 kV alternative using HPFF cable having the largest potential rate impact and the Kamoku 46 kV alternative having the smallest potential rate impact. The 46 kV Phased Project has a potential incremental rate impact of $0.72 in 2007, which increases to $0.90 in 2009.

Q. Does this conclude your testimony?

A. Yes, it does.